Local Power Comments on The 2005 Draft Integrated Energy Policy Report

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Local Power and Community Choice

Local Power is responsible for bringing the idea of Community Choice to California, after having secured its passage in Massachusetts and Ohio. The purpose of Community Choice is to give local governments the power to provide for the energy needs of their communities in an economically and environmentally sound manner. Under California's Community Choice Law (AB117, Migden), local authorities, called Community Choice Aggregators, can develop innovative plans for cleaner power, and contract to have these plans implemented by an independent Electric Service Provider. In this way Community Choice is an alternative to the large electrical companies that currently provide most service in the state. It is also much simpler to develop than a municipal utility, which requires purchasing expensive transmission and distribution systems and setting up a large and complex administrative organization. Community Choice Aggregators can utilize the low cost financing of tax free revenue bonds to finance locally owned and controlled renewable energy and some energy conservation resources.

San Francisco is the first city in the state to pursue Community Choice by a series of actions. In 2001 the City passed two solar bond measures by means of popular initiative, VoteSolar's $100 million Proposition B, and Local Power's Solar H-bond Authority. Both passed by a significant margin. Since that time the unanimous Board of Supervisors, with the signature of Mayor Gavin Newsom, passed the Energy Independence Ordinance (86-04) which declared San Francisco as a Community Choice Aggregator (CCA). This ordinance, which Local Power drafted for sponsoring Supervisor Tom Ammiano, requires the City to build 360 megawatts of distributed, renewable, and energy efficiency infrastructure. In May 2005 the Local Agency Formation Commission (LAFCO) approved Local Power's draft Implementation Plan (IP) required by law prior to contracting with an Electric Service Provider (ESP). This is now before the Board of Supervisors. In addition to the 360 MW of new resources, the Implementation Plan calls for achieving a 51 percent renewable portfolio by 2017, far beyond the current legal requirement of 20%. Over twenty cities and counties in the state, including some of the largest jurisdictions, have participated in a study funded in part by the California Energy Commission and the US Department of Energy, to establish the feasibility of implementing a 40% by 2017 RPS as Community Choice Aggregators (CCAs).

Metamorphosis of the Grid

Local Power is particularly interested in the development of urban energy self-reliance. While we do not envision cities cutting themselves off the grid any time soon, there are clear benefits to balancing the structure of the current electric grid system, some of which are listed in a general way in the 2005 Draft Integrated Energy Policy Report (IEPR). (1)

The current electrical system is built upon a linear conceptual model that has inherent limitations. Urban environments, long the dependent "consumers" of energy, can play a much more constructive role as CCAs and be transformed into major energy resources. The current loading order is already setting the stage for this by placing the highest priority upon energy efficiency and conservation, followed by renewable and distributed generation.

These new energy resources make much better neighbors in the urban environment, and are superior to their predecessors in a number of ways. Their emergence is already transforming the grid from a linear model into a dynamic network, more like a communication system. In many ways the beginnings of this new energy system are already in place, and the transition to a new paradigm is bringing them to the fore; as with regional wireless markets, CCAs offer a regional, demand side-driven opportunity for these new technologies in much the same way that the Federal Communication Commission's Metropolitan Service Areas and Rural Service Areas provided the revenue basis for the wireless revolution.

The recent discovery of the significance of distributed cogeneration to the electrical system is an important example. Cogeneration, which recycles the heat used to generate electricity, at its best, reaches an efficiency of 90%, an achievement that leaves the finest central power plants in the dust. Cogeneration is currently as important to California as nuclear power.

Whereas wireless created the PDA, the PCS/GSM phones and now Wi-Fi (also appearing on a municipal basis), green Local Power technologies will deliver unprecedented greenhouse gas reductions and scaled, sustainable economics for technologies like solar photovoltaics. Specifically, CCA solar is a long-awaited dynamic response of customer energy usage to grid conditions. Alongside the CCA's clear contribution to the growth of distributed renewables such as solar, CCA efficiency and conservation provide the other key components of an interactive grid.

All these elements are mentioned in the Draft IEPR, yet distributed resources need to be better highlighted in the Report. They are a solution to problems of resource depletion, environmental impact, and the expensive, unsustainable and highly insecure strategy of expanding transmission capacity to meet growing load in California. The interactive and distributed grid is the essential next stage of transformation of the electricity system, which will allow distributed resources to function properly, and achieve a much better integration of the energy system with both the human and natural environment.

The Disadvantages of Centralized Power

The primary conceptual model of the current system is to place large generators at significant distances from urban centers, send the power over long distance transmission lines, split the power through a distribution network, and finally consume the power by commercial and residential "customers". We will designate this as the "linear broadcast model" of power generation, and even though it exists in a network it still conceptually moves in one direction along a line:

The Broadcast Model of the Electricity System

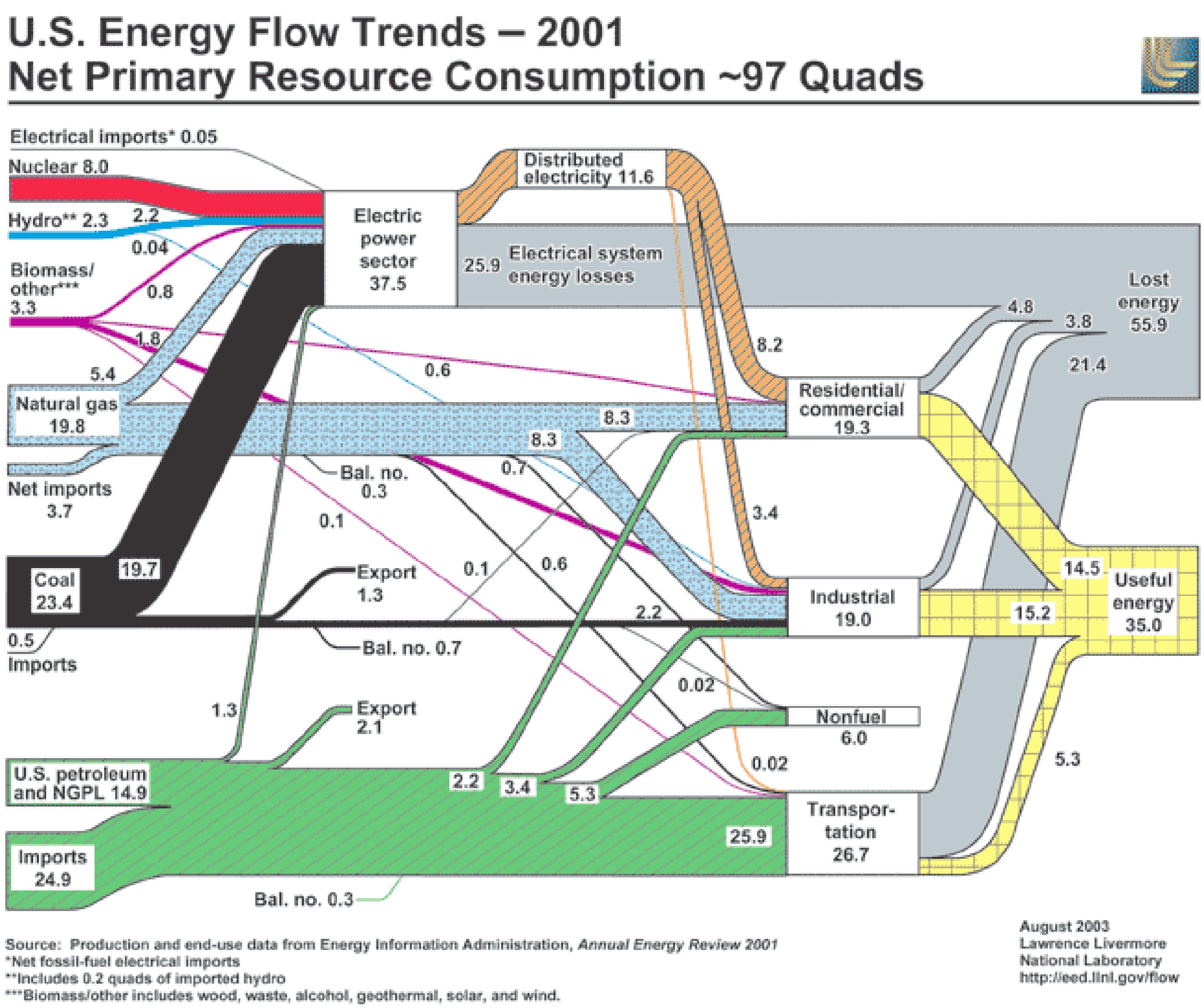
Fuel ==> Generation ==> Transmission ==> Distribution ==> Consumption

While there are advantages to sending electricity resources over a long distance, there are also major problems. Primary reliance on mega-grids creates vulnerability to collapse of electricity supply for whole regions of the country, and can take days to repair. The economic losses from such events are massive, making transmission over-dependence a critical security weakness for Emergency Medical Response (EMR) planning. This system can potentially be brought down by human error, solar storms, power over- or under-load, broken wires, failed transformers, power plant outages, short circuits, natural disaster, acts of violence, demand spikes, and other causes. In a way, it is amazing that grid collapse, rotating blackouts and brownouts do not happen more often.

An even more serious problem is the daily waste of energy through "line losses" in the grid created primarily by the natural resistance of the wires, but also through other more subtle effects. The Energy Commission has estimated that 8.6% of electricity is lost in the transmission and distribution system. (2) For 2006 this net loss has been projected at 23,601 gWh, about the total annual consumption of San Francisco and San Diego Counties combined. (3)

Transmission is one inefficiency embedded in the current system of centralized electrical generation. Another is in the power plants. Decades of regulated protection from competition has created a fleet of power plants with an extraordinary level of inefficiency and pollution. Typical fuel conversion efficiencies range between 30% and 40%, with an average in California of 32.4% as recently as 2003. (4) While this has improved over the last two years, the most efficient combined cycle natural gas plant cannot exceed 60% efficiency, and much lower efficiencies than this are more common— especially for nuclear, coal, and oil plants, but also for gas "peakers".

The net result is an electrical system that nationally wastes 69% of the energy input. (5) And this is before it ever gets to a wall socket. The following flow chart illustrates the vast waste in the primary energy systems in the US, measured in Quadrillion BTUs (Quads):



After the electricity gets to the plug the flow chart shows one fourth of the remaining energy from electricity and direct fuel sources for residential, commercial and industrial applications being "lost". But this is very conservative, and it understates the degree to which electricity resources can be wasted. For example, electric lighting during the day could in many cases be reduced or eliminated in exchange for natural solar lighting. And electric lighting is itself one of the most notoriously wasteful "appliances" that we have. A typical incandescent bulb, considered by itself, is only about 5% efficient. (6) When plugged into the wall it productively uses 5% (light efficiency) of 33% (electric system efficiency), which is a system throughput efficiency of 1.6%.

The classic scientific illustration of the inefficiency of centralized electricity systems is that over 98% of the initial energy is wasted when an American turns on an incandescent light bulb. This is perhaps a most dramatic example of the absurd waste of our central electric power system.

Unfortunately, the disadvantages extend well beyond mere inefficiency and push themselves toward the further reaches of local and even global catastrophe. Catastrophic climate change, of which power generation is the leading cause (e.g. 25% in San Francisco), is melting glaciers and the polar ice caps at an alarming rate, and feeding more extreme weather patterns that increase both desertification and flooding in different regions of the world, breeding poverty, social strife and disease. Mercury poisoning from coal plants is now believed to lower the IQ of children even as we pour billions of dollars into the education system. These same plants release more radioactive isotopes than the nuclear plants of the world, and numerous other pollutants associated with adverse health effects. Power plants cause billions of dollars of damage to infrastructure and crops. In addition, the great powers do, and may increasingly in the future, throw themselves into conflict and sometimes war over depleting energy resources, even as these same energy resources deplete our collective security. In the past year the Pentagon released a report that showed climate change to be a greater threat to national security than terrorism.

As if that were all not enough, the entire energy system has been actively pushing the boundaries of social inequality, by accelerating the concentration of wealth in the hands of a few, and by forcing those who have neither wealth nor political clout to be the first to inhale and consume the pollution of the power companies. Transmission is therefore an economic justice issue. Socially active minority groups have been protesting for years the siting of old dirty Hunters Point and Potrero power plants in San Francisco. Nationally, numerous other complaints of social and environmental injustice have been brought against existing and proposed power plants, whether in an urban ghetto or an Indian Reservation.

The CPUC's approval of the Jefferson Martin line and other new transmission projects underscores another important problem with transmission overdevelopment: the public health impacts of Electromagnetic Fields from High Voltage power lines on the residents that live near them. With public opposition to new transmission having a strong basis in science, state agencies should promote any opportunity to reduce the need for future new transmission highways in Califonria.

It would be useful, if even only in a few pages, to include a chapter in the IEPR that assembles a picture of the various “external” impacts of California’s energy systems. The Pioneer Line, the Burning Man Coal Plant and other decisions to outsource new polluting power plants into neighboring states underscores the risk of building new transmission to solve Califonria's ongoing energy problems.

Notes:

1) The summary of benefits of distributed generation (DG) is quite brief: “The benefits of DG go far beyond generation. DG reduces the need for new additions to the state’s transmission and distribution infrastructure and improves the efficiency of the system by reducing losses at peak delivery times. Customers can use DG technologies as either peaking resources or for energy independence and protection against supply outages and brownouts.” One of the principal aims of this section is to show how these points can, and in our opinion should, be developed to make clear what the full potential is, how benefits also accrue to energy efficiency and conservation resources, and how dramatically the concept of efficiency and conservation feed reciprocally back into current inefficient system of generation and transmission of electricity.

2) 1980-1997 Calif. Statewide Electricity Consumption, With Forecasts to 2007 - (PDF file - excerpt from 1998 Baseline Energy Outlook, August 1998.) TABLE A2; STAFF’ STATEWIDE OUTLOOK FOR CALIFORNIA, NET ELECTRICITY FOR GENERATION LOAD (gWh)*, STATEWIDE_CONSUMPTION.PDF. California Energy Commission.

3) 2000 Calif. Electricity Deliveries By County - Residential & Nonresidential, California Energy Commission.

4) 2005 Draft Integrated Energy Policy Report, p. 50 reports that the average heat rate of generators in California in 2003 was 10,550 Btu/kWh, nearly three times the energy consumption of a "perfectly efficient" generator that would only require 3419 Btu of heat to generate a kilowatt hour of electricity.

5) Out of 37.5 quadrillion Btu total input into the US electric system, 25.9 quads were wasted. Only 11.6 quads was useful electricity. US Energy Flow Trends- 2001, Lawrence Livermore National Laboratory, August 2003.

6) Incandescent bulbs produce 10 to 15 lumens per watt; over 200 is theoretically possible. Compact fluorescents (CFs) put out near 60 lumens per watt. Most Cfs degrade in output, and have an average lifetime efficiency near 25%. This pushes efficiency (CF light plus electric system) to a depressing 8%.

Transforming the Distribution Network into a Resource

The current regulatory framework heavily favors the "broadcast" model of centralized power generation. If the potential of distributed resources is to be realized, more than just a change of rules will be required. We will really need to change the state's conceptual model for how to make these distributed resources work. Fortunately many of the key elements already exist, but they are only applied on the other end of the wires, for central power plants. To understand the problem, and the necessary solutions, consider the case of two renewable resources: one is a wind turbine at a large wind farm and the other a solar array on an urban rooftop.

The Wind Farm and the Solar Array

Overwhelmingly, the largest implementation of wind power has been in rural wind farms located many miles from urban load centers. Wind suffers under the burden of being intermittent, and its productive potential is not necessarily coincident with load requirements. Yet, representatives of the renewable industry at recent hearings on the Draft IEPR have insisted that this is no longer a problem for the wind industry. How have they solved this problem?

Three critical tools have been developed. One is the ability to spread wind turbines over larger geographical regions and combine their output, both at the bus bar at individual wind farms and by multiple wind farms in the grid as a whole. Wind varies in different locations, and these variations tend to cancel each other out. (1) A second critical tool is careful measurement of the electricity generated by wind farms, combined with forward projections of output. In the last few years the ISO has been working to develop such models so that variations in wind generation can be predicted with sufficient advance notice so that the grid can adjust. The prediction models have been taken a step further by the wind industry to coordinate output of wind power with gas turbine generation, and these are packaged together in a contract for firm power. Wind/gas contracts can thus serve as reliable base load. A similar model was developed for the large solar thermal plant in Southern California.

An almost diametrically opposite picture is presented by the typical PV system installed on an urban rooftop. Each PV system is implemented one at a time, in a sense as individual packets that cannot be coordinated one to the other. One PV system is tied to one customer, one property, one physical address and one electric meter. Rebates are handed out one at a time, without regard to system needs, and are tied only to this "on-site" requirement.

If policy is constructed to encourage this one-at-a-time, individually "shrink-wrapped" deployment, there will be little effort to integrate production between PV systems in a locality, or across the grid in an optimal way. For example, a fixed array pointing South helps load mainly a couple hours on either side of local noon. This may not necessarily match the shape and duration of the peak requirement in a region, or for a distribution system coming from a given substation. If the PV systems cannot match the load shape, then additional capacity in remote generation and transmission may have to be built. This will undermine a significant part of the potential economic value of PV to the grid. (2)

A second barrier to making the PV system into a real resource is the fact that it is not independently measured in the way a wind farm is. Customer owned PV is placed "behind" a net meter, which combined the output of the PV system with the on-site load. This effectively hides the PV resource from the grid, and prevents any assessment of its real time output or its economic value. The lack of independent measurement blocks the third element above granted to the wind farm: the coordination with other dispatchable generation sources. This last prevents PV from being firm capacity that can be relied upon.

These problems, which affect all distributed resources to one degree or another, are by no means inevitable. There are number of tools that can be used, and existing regulatory barriers that can be reduced, to facilitate competitively priced distributed renewable resources. Up to now these resources have had a limited role compared to their potential, and this is not only due to policies. Real challenges of cost, reliability, and the comparative complexity of using many smaller sources in the grid, have been part of the picture as well. In particular, the relatively small amount of distributed renewables has made it unnecessary to do much system planning. As these resources grow in presence, the technical and economic barriers to a higher level of integration into the grid are falling away, and much of the emerging value of distributed resources can be tapped today.

Integrating Distributed Resources

Distributed resources are remarkably diverse and include: small scale wind turbines, photovoltaics, local tidal and wave generators, geothermal heating, cogeneration, micro-turbines, fuel cells, biofuel combustion, digester gas from municipal waste, energy recovery from natural gas and water pipelines. Distributed solar thermal energy can reduce demand for electricity when it is used for cooking, water and space heating and cooling, and desalinization of sea water. Solar thermal energy can also be used for electrical generation. There are also tremendous opportunities to reduce energy consumption through deployment of energy efficient appliances, buildings and other infrastructure, and demand reduction through use of day lighting during the day, and dark sky ordinances to reduce nighttime over illumination. Demand can be controlled with tools such as sensors that respond to human presence, timers that insure lights and space heating and cooling won't stay on indefinitely, radio controlled cycling of air conditioning loads, and economic structures such as time of use and real time pricing.

Much can be gained by focusing policy tools to support integration of distributed resources. And integration may be the best way to bring improvements to performance of each piece of the demand-side network.

One example that has been explored by the National Renewable Energy Laboratory is connecting on-site load control with photovoltaics (PV). Since PV only produces when the sun shines, there is a problem with reliability. This can be addressed by integrating the load controls of the air conditioner so that, for example, it is turned off when a cloud passes over the building. Since there is far less heat gain to the building during this time, integrating these two technologies is a natural fit. There is less burden on the building occupants than if there were an arbitrary cycling procedure, and the concern about intermittent PV production is reduced significantly. The interaction of demand controls with PV has the potential to remove real load burdens from the grid.

The example above shows what is possible through integration of systems at a single site. Much more is possible if distributed resources are integrated into a network. For example, the angles of fixed solar arrays in various sites can be deliberately oriented over a range of positions that spreads out the aggregate PV production over a longer period of the day to better match the demand curve.

The establishment of micro-grids, where local resources can be shared in a neighborhood, would be one excellent way to make this kind of sharing feasible. The micro-grid is a network of distributed generation bound together with a local load. Micro-grids offer the opportunity to develop generation and demand that is highly tailored one to the other. It is also an excellent way to implement renewables in a cost effective way. A community solar project can be placed in a location of maximum sun, and oriented to match neighborhood demand needs. The PV system can be built to a larger scale, and thus be more affordable per unit of generation capacity as well as on a cost per kilowatt-hour basis. The economic benefits of scale could, over the life of such a community solar project, rival the value of a rebate. (3)

Larger scale integration, such as a Community Choice Aggregator such as a city or county could provide, could monitor to output of local intermittent renewables and correlate them to the dispatchable load of a cogeneration system. To begin with it would be most valuable to monitor the output of larger distributed generation, but the feasibility of developing cost-effective central, real-time monitoring of smaller systems should be pursued.

Notes:

1) The ability of wide placement of wind turbines to reduce variations in output was the subject of a study on a few wind farms in the Midwest, but is a well known effect. See the report: Short-Term Output Variations in Wind Farms—Implications for Ancillary Services in the United States. September 2000 • NREL/CP-500-29155

2) The value of PV to the grid is substantially larger than the average cost of transmission and distribution, because it displaces peak power. Avoided peak transmission costs per kilowatt-hour are large for the same reason that electricity from peaker plants are high: the low utilization of that portion of the fixed capital resource. "The estimated benefit from avoiding or deferring power line upgrades is estimated to be between 4.5 cents and 10 cents per kilowatt hour."; QUANTIFYING THE BENEFITS OF SOLAR POWER FOR CALIFORNIA, A WHITE PAPER; by ED SMELOFF; JANUARY 2005, p. 6.

3) Small scale 2 kilowatt residential PV system costs near $9/watt to install, and likely an additional $2/watt for inverter replacement over a 30 year lifecycle. A 50 kilowatt system serving up to 25 homes might save $1/watt on the installation, and utilize a longer lasting inverter. The total savings could be as much as $2 to $3/watt.

Regulatory Reform

The Draft IEPR makes excellent suggestions about the need to ease integration of distributed resources. Though these suggestions are mentioned only in the context of combined heat and power plants (CHP), the same could be said of all distributed generation. Perhaps the most important of these, which we suggest be highlighted as primary recommendations of the entire report, include:

- Regulatory rules should be friendly toward interconnection of distributed generation, particularly avoiding the requirement for FERC interconnection agreements and wholesale ISO tariffs. DG should be designed, and perceived by regulatory bodies, as removing cost and burden from the larger grid. (p.65)
- Revenue streams should assure that load serving entities (the report says only "utilities") not have DG impose a net cost upon them, at least arriving at the point of revenue neutrality (p.66)
- Eliminating the "on-site" requirement for DG, by allowing "over the fence" and "wheeling" transactions (p. 64)

To these recommendations Local Power would like to add seven key policy tools that can greatly help in integrating renewable and distributed resources in an affordable way. These are not in themselves new tools, for the most part, but are the application and coordination of existing tools that are not yet adequately applied, but could be.

Measurement: turning distributed renewables into a resource

We recommend that distributed generation sources be independently metered to the greatest extent feasible, and that this data be centrally monitored in real time by computer data bases. Such monitoring can be aggregated by load serving entities so as to lift that burden from individual small generators. Independent monitoring will lift the veil placed by net meters upon the actual output and value of on-site distributed resources, and models can be developed to facilitate forecasting of DG system production, similar to the way wind power is currently forecasted.

Incentives for value

We recommend that incentive payments be restructured to pay for value to the grid and society, and not have rebates only given for installed capacity. Such a restructuring can build upon the independent measurement of distributed renewables as performance incentives that can be structured in different ways. A valuable proposal that was in the recent Million Solar Roofs bill (SB1, Murray) was to give larger incentive payments to customers that integrate energy efficiency savings with a PV system. Full removal of load in the form of contracts, which would include integration of demand reduction, is another possible example, as are other integration proposals discussed in this paper.

Another value component is on the cost side of the value equation. Currently rebates are given no matter how much a PV system costs per watt. Rebate rules could be restructured to favor proposals that lower the cost of PV, such as community solar projects, and cooperative large scale purchases of modules.

The general approach to rebates has been to set a high level and then reduce them if other local rebates or financial benefits are offered. We see this as working backwards. A more "value for dollars" oriented approach would be to seek for ways to leverage funds with other resources in a constructive way. The examples above show some ways this might be done. It is better to reward approaches that save money or provide matching grants instead of guaranteeing payment priority to the highest cost and least financially supported systems.

RPS

Currently, distributed renewable generation does not count toward the renewable portfolio of any entity. A market for renewable credits does not need to be established to make this happen, only a system where rights are transferred to the local load serving entity. The rebate payment, or even better a performance incentive, can serve as a purchase of such credits. This will provide some realization of value for distributed renewables that they otherwise would lack, and in turn will give a value in return for public good payments.

In some other states photovoltaics in particular is given special RPS status, and counted as worth anywhere from 1.25 to 3 times a normal RPS credit. This has good justification to the extent that local generation avoids other costs and that solar energy is produced at peak times when the dirtiest and least efficient resources are usually brought on line; not to mention eliminating the need for new transmission development.

We recommend that payments for real-time measured kilowatt-hours be made as a purchase of renewable credits for distributed renewable generation sources. Extra credit should be given for each benefit that is added. The following schedule could serve as an illustrative framework:

Distributed renewable	1.25 credits
Distributed peak or off-peak firm renewable	1.50 credits
Distributed firm peak renewable	2 credits

The framework should be set to reasonably demonstrated value to the grid or other public benefits. For example, distributed renewables avoid the nearly 9% average transmission loss and provide protection from other power losses for the entire local distribution network, especially during peak hours. (1)

Tax Policy

New tax laws have extended or increased tax credits for individuals and businesses building certain types of energy. For example, PV will have 20% federal tax credits for residential PV up to a limit of $2000, while commercial enterprises can take a 30% on any sized PV system. Both of these credits run from 2006-07, and they will significantly undermine the value of rebates given during that time. California's rebate system, if extended during the next two years, risks loss of $100 million in value or more. This topic is presented in a separate, appended document in more detail, and illustrates the importance of coordination between policies.

Financing: Don't spend it, lend it.

The Energy Commission should examine the impact of financing upon the cost of DG and particularly renewable DG. Various financing formats can make expensive investments, in what is essentially energy infrastructure, far more affordable. Other countries, such as Germany and Japan, have facilitated the growth of renewables, especially PV, with large funds that give low or no interest loans. These are typically administered through banks. Such loans can eliminate costs that might actually be worth more than the value of a rebate, but they must be integrated with tax policy to assure that they do not void tax credits. For this reason loan programs will probably be much more cost effective if they are given to non-taxpaying entities. Since funds are not actually spent in a loan program, they may prove to be both more palatable to the state, as well as a more frugal use of resources.

Integrating Resources

Local Power strongly disagrees with the recommendation that "the Energy Commission and CPUC should separate CHP from DG in the next version the Energy Action Plan so that CHP issues and strategies are not subsumed by broader DG issues and strategies." (Draft IEPR, p.65) CHP is the single largest component of DG by far. If it is pulled out of the realm of DG it will not only strip DG of most of its significance, it will also stand as a conceptual and regulatory barrier to even perceiving the type of recommendations that are being proposed here. CHP, as a dispatchable resource, could be the backbone that allows distributed renewable resources to function optimally. Separating them must be regarded as a threat to making DG an economically viable option. A major value of solar energy, for example, can only be realized if DG resources can reliably remove load from the transmission system. This value is essentially robbed from DG renewables if new transmission lines and more remote power plants are built. Then there are no avoided cost, only duplicated ones.

Local Power recommends that the Energy Commission coordinate with other regulatory bodies to fund a series of studies leading toward implementing coordination between distributed resources. These should include PV-demand response systems, load removal contracts, central data collection of distributed generation, micro-grids and using CHP plants to support distributed renewables, and other integration strategies that can enhance the value of DG.

Community Choice

Community Choice is designed as a way to bring these various policy elements together. Local Power means the ability of cities and counties to establish their own clean energy independence. This infrastructure needs to work together in a harmonious way, and we hope that CCAs forge the path into the new power paradigm that emphasizes local distributed resources. Barriers need to be lifted that discriminate against community cooperation and integration of distributed generation and large scale energy efficiency programs. If state and local policy makers share this vision and recognize the potential of CCA to help deliver on RPS promises by state agencies and the legislature, they can help bring about a much more fruitful implementation of Community Choice and with it the success of the RPS.

Notes:

1) A recent report on SMUD's distribution system showed that the benefits of distributed generation go beyond the avoided losses for the power generated, they actually protect from other losses as well. A 100 kw generator can save between 3% and 10% of the power from being lost in the local distribution line. See 2005 SMUD report by Energy and Environmental Economics, Inc., et. al.: Renewable Distributed Generation Assessment: Sacramento Municipal Utility District Case Study, January 2005; CEC 500-2005-XXX

Local Power Comments on Topic Sections of the 2005 Draft IEPR

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Comments on Electric Resources

Local Power is concerned that the forecasts for increase in coal and natural gas in the electric generation sector do not take into account the implementation of RPS goals. Doubling the current state renewable levels will have a significant effect on the need for other sources of electricity. The announced goal of the governor's and Energy Commission's recommendations to go to 33% RPS by 2020 (Draft IEPR, p. 90) will dramatically reduce the projected needs for natural gas and coal power. Here is the table of current resources given by the Draft IEPR, with a rough projection of how the growing role of renewables might affect that state's portfolio in the future:

Power supply:	2004	2010	2020
Natural Gas	41%	37%	28%
Nuclear:	13%	12%	10%
Coal:	21%	19%	16%
Hydro:	15%	14%	13%
Renewables:	10%	20%	33%
Total:	100%	100%	100%

The capacity of nuclear, coal and hydro power is assumed to be near what it is today, but decreasing in percentage of overall supply as electricity demand grows. Some modernization of existing hydro generators could increase their efficiency to produce 10% to 15% more power than they currently do, which slows the reduction of hydroelectricity in the portfolio. Because the other sources of generation are held within certain fixed parameters, particularly the capacity for nuclear and hydro-electricity, and renewables are assumed to grow on the state's schedule, the balance of energy from coal and natural gas must necessarily decrease substantially. Otherwise the state would appear to be planning not to deliver on its RPS promises.

As the policy choices are currently being directed they do not seem to take the effect of this dramatic shift into account. The rate of growth for electricity demand would be the only thing that could even maintain the current level of demand for coal and natural gas. Under the scenario where renewables grow as planned, it is far more likely that the role of coal and natural gas will begin to slip significantly as newly developed renewable power facilities take their place. We urge the state to include such modeling projections in the final IEPR, and to incorporate these into the range of scenarios of future need. These projections have important ramifications for long term contracts (over 5 years) for natural gas generation capacity. Any push for long-term commitment to fossil fuel generation risks a direct conflict with the growth of renewables if such contracts are set up without seeing their effect on future portfolios desired by the Commission.

Comments on Energy Efficiency

Pages 56-60 Draft IEPR

"Through 2003, California's programs have saved more than 40,000 gigawatt hours (GWh) of electricity and ..."

This needs a base year, and clarification. Is this total electricity savings over a period of years, or savings per year compared to a projection made from an earlier year?

The 2003 Energy Report *concluded that the maximum achievable electricity savings from future energy efficiency programs over the next decade are an additional 30,000 gWh.*

Again is this annual savings or total over the period? If it is annual the figure is impressive (over 10% savings), if it is a total over 10 years than it is extremely small (only 1%).

the CPUC adopted aggressive energy savings goals designed to mine this potential. When these goals are realized, ...

This appears premature to assume that a future projected goal will indeed be met; it might be better to say "if these goals are realized..."

goals, the CPUC significantly increased IOU energy efficiency funding to $823 million for 2004-2005,[81] and has proposed funding for 2006-2008 programs of $1.98 billion.

It would be helpful to explain, at a minimum, in some general way the nature of these programs and how this money is to be allocated, especially since this is the state's primary program in this domain. A paragraph and a breakdown table of how these funds are likely to be allocated and what benefits are expected to be derived from each portion, likelihood of success, policy issues affecting the program, etc., would be great.

Although demand response is currently a controversial subject, California must address the increasing number of peak load hours to improve system reliability and temper electricity price volatility. The Energy Commission and the CPUC need to make major efforts over the next few years to determine the appropriate mix of voluntary and mandatory demand response programs, as well as the right mix of price-sensitive and reliability programs.

There are other options to the polarizing opposites of "voluntary and mandatory". For example, rate payments or reductions can be established based on contract agreements with customers to remove load during agreed upon hours if the system requires it. Such contracts would be similar to RMR contracts that the ISO signs with generators; the contract binds the generator to give adequate reliability, but the contract itself is voluntary. Load reduction can be coordinated with local distributed and renewable generation resource, particularly PV, which can buffer the excessive burdens of demand reduction.

Comments on Community Choice

Local Power is concerned that the current Draft IEPR document contains a misstatement about Community Choice Aggregators currently experiencing difficulty meeting the RPS requirements. At this point no such difficulty exists, as no CCA has yet gone into operation, and none will until at least next year. Whether there is or is not a difficulty will depend significantly upon the implementation rules for CCAs achieving the RPS. Current law requires an increase of 1% per year, which rate of increase we believe all CCAs should be able to meet easily. Current law also requires that all CCAs achieve a 20% renewable portfolio by 2017, which we also believe that all CCAs should be able to meet. The challenge will come if CCAs starting after 2006 will be required to meet the 2010 target. For example, will a CCA starting in 2010 be required to achieve a 20% renewable portfolio in the first year? If so, then perhaps they should be required to obtain what renewables they can from the beginning, and allowed to take a share of renewables that are under contract with the IOUs, provided that they do so in an amount no greater than the load they represent, and thus do not reduce the portfolio percentage of the IOU.

While renewable energy certificates (RECs) may in fact be necessary for CCA's achieving RPS goals in the short run, we believe that resorting to REC purchases should be a last choice. In our view CCAs should be building their own renewables to the greatest extent feasible. RPS rules such as stated above, and other facilitating recommendation given in this paper, are preferable to purchasing of RECs from remote locations. In this way we have a slightly different angle from the recommendations of the Draft IEPR regarding CCAs: we are not opposed to use of RECs, but believe that other policy changes are more fundamentally important in the longer term.

Local Power supports the recommendation of the Draft IEPR (p.49) to urge the CPUC to establish rules for CCA load departure and return as soon as possible, and would prefer if the commission would do this in the first half of 2006 instead of waiting until the end of the year. Local Power also agrees with the draft report (p.48) that the CPUC's use of exit fees will adequately protect IOUs from stranded costs associated with long-term contracts, though we also think that this should be tied to the right of an option to take delivery of the power associated with that stranded cost if the CCA desires to do so. Otherwise, as pointed out by parties in CPUC R.03-10-003, the CCA customers would be charged once for power they are unable to dispose of (the Customer Responsibility Surcharge), and second for the power itself.

Comments on Natural Gas

Local Power is concerned that the Energy Commission forcasts do not adequately examine the question of resource depletion, particularly in North America, but also globally. We forsee the likelihood of significantly higher prices for natural gas, especially if those prices forcasts are extended over the 30 year life of new natural gas plants. It appears exceedingly likely to us that future prices within the life of new plants will match or exceed, on a sustained basis, what we have seen during this post-hurricane disaster season. This would push generation costs to a level that is higher than the likely future cost of almost every renewable technology that is currently in use or development.

We urge the authors to include two of the charts in the supplemental staff report on natural gas in the IEPR itself, since they are of extraordinary significance. One of these shows the depletion rate of gas wells in the US. This should be more fully explained. It seems to suggest that the average rate of decrease in output of all wells combined in the US around 1990 was about 50% over a 5 year period. This accelerated to an average of 50% decline in output in only two years. To say that this development is staggering risks understatement.

A second chart we recommend for inclusion in the IEPR shows reserves and ultimate potential of all major gas fields in the Western US and Southwestern Canada. The potentially recovered supply from this region, which includes most of the natural gas capacity of the lower 48 states, represents a 16 year supply for the nation as a whole. This is a rather sobering fact, and we wonder whether it is incorporated into the production and price forecasts.

Unfortunately, both of these charts are poorly reproduced in both the printed and online version of the supplemental report. We request that staff put in a clean copy of these images, and give a better explanation and summary inventory of the numbers. They are very ominous signs for the future 10 to 30 years out.

We question the projections regarding the impact of LNG imports on domestic prices. With the state's commitment to an RPS acceleration and San Francisco and other cities representing a major portion of California's electricity load seeking to implement an ever higher 40% RPS by 2017, imported LNG should not be needed to power any new additional natural gas generation. However, if the state continues to plan for new gas-fired generation even though it is not needed, the U.S. economy could become dependent on LNG to power its domestic power plants supply.

LNG advocates and their servants have claimed that LNG will lower the price of natural gas in California. However, there are serious questions about LNG's actual impact on prices. Historically, LNG prices have followed the prices of domestic gas, and international gas prices have followed the price of petroleum. The prospect of petroleum staying low for many more years is in serious doubt. The former oil minister of Saudi Arabia is predicting a global peak of 93 million barrels a day in 2015. This will have a major impact on global oil and gas prices after that point in time. In addition, demand in Asia for natural gas will compete with the growing needs of Europe, particularly as many nations there try to comply with the Kyoto treaty. They are bound to reduce coal use, and petroleum has already almost vanished from the electric industry in that part of the world. Nuclear power may have some resurgence, but there is still much opposition to it both here in the US and in other countries seeking to decommission their plants, such as Germany, or fearing military proliferation of nuclear materials, such as in Iran. As the use of renewables will increase, so will the use of global natural gas supplies increase as coal and petroleum continue to be phased out worldwide. The indications for future global natural gas prices do not point to "cheap" as one looks further out into the decades ahead; investing in LNG now amounts to a kind of debt-financing.

The commission should include a section in the IEPR on North American and global fossil fuel depletion, with inventory and projections of years left of known and potential supplies.

Comments on Transportation

Local Power urges the commission to look into a range of transportation issues that directly affect the efficiency of the system. While our principal focus is not in transportation, there are a number of policy recommendations that could make a major difference. The draft IEPR's recommendation to include renewable fuels in gasoline formulas is an excellent way to transition away from imported fossil fuels. Major improvements can be realized by increasing the average fleet mileage and we support any such efforts. The state should certainly urge the federal government to pursue this, and the state should evaluate what it can do as well.

We see transportation as also a significant local issue. The vast majority of travel for automobiles is for trips of relatively short distances. One recommendation we have is that alternative transportation technologies such as the Segway should be encouraged, not banned from sidewalks. Additionally, local and state government can directly implement the increased use of timed traffic lights. This simple measure alone, if properly carried out, could significantly reduce fuel consumption. According to the Institute for Transportation Engineers:

> There are about 300,000 traffic signals in the United States alone and over 75% of them could be improved by updating equipment or adjusting the timing. Traffic signal retiming is one of the most cost-effective ways to improve traffic movement and make our streets safer. Comprehensive signal retiming programs have documented benefits of 7-13% reduction in overall travel time, 15-37% reduction in delay and a 6-9% fuel savings. (1)

They projected that such a program would cost about $1 billion nationally per year, yet return $40 billion in gasoline savings. A program in California would cost about 1/10th of this, about $100 million/year and would return the investment between ten and forty fold in saved fuel costs alone. This has to be one of the most easily accomplished and cost effective suggestions known to us. It is something that can be done in-state and locally and it would save millions of hours of time lost waiting for traffic lights to change.

Notes:

1) http://www.ite.org/signal/index.asp